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ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 86-4

To: All Oil and Gas Operators

18 April 1986

CLASSIFICATION OF WELLS DRILLED FOR OIL AND GAS IN ALBERTA

This letter supersedes Informational Letter IL 84-5 issued on 16 May 1984.

Informational Letter IL 84-5 was initiated by the Alberta Government's Oil Royalty Exemption System which pertained to Board-classified exploratory wells spudded between 31 March 1984 and 1 August 1985. That letter described the various classes of exploratory and development wells and the Board's well classification procedures.

The purpose of this letter is to reiterate those definitions and procedures in the context of the government's recently announced EXPLORATORY DRILLING ASSISTANCE PROGRAM (EDAP). Apart from the clarification of certain wording, the earlier letter is essentially unchanged, although its section on discovery pool status has been deleted because it is irrelevant to the new program. Also, the earlier letter referred to a $75 appeal fee which will be increased to $100 on 1 May 1986. Experience has shown that a payment of at least $100 is necessary to recover the cost of performing this service.

This letter should be reviewed in conjunction with Alberta Energy and Natural Resources Information Letter 86-10, copies of which are available from the EDAP Calgary office, 855 - 8 Avenue S.W., Calgary, or from Alberta Energy and Natural Resources at either the 8th floor, Petroleum Plaza, North Tower, 9945 - 108 Street, Edmonton, or Room 807, J. J. Bowlen Building, Calgary.

1 DESCRIPTION OF THE WELL CLASSIFICATION SYSTEM

The following is a description of the Lahee well classification system. The system has been used by the Board for over 20 years to provide a standard basis for compiling drilling statistics.

1.1 Exploratory Category

The exploratory category consists of the following four classes of wells. A well licensed under this category contains exploratory metreage from ground level to total depth except in the case of a deeper pool test which is described under clause (c).

(a) A new-field wildcat well (NFW) is a well located at a considerable distance beyond the limits of known pools and drilled in a geological environment where oil or gas has not yet been discovered.

(b) A new-pool wildcat well (NPW) is a well located at a relatively considerable distance outside the limits of known pools, or drilled in a geological environment where other pools have been found but where, in the Board's opinion, the complexities in the geological conditions are such that searching for a new pool is hazardous. The objective of a new-pool wildcat well is the discovery of a new pool in an area known to contain oil or gas.

(c) A deeper pool test well (DPT) is a well located within the established or expected limits of a pool or pools and drilled with the objective of searching for undiscovered oil or gas below the deepest such pool. Only the interval from the base of the deepest established pool to total depth constitutes exploratory metreage at a deeper pool test; the remainder of the drilled interval is regarded as development metreage.

(d) An outpost well (OUT) is a well drilled with the objective of extending, by a considerable distance, a pool already partly developed. Its original objective is the producing or producible pool, although it may be completed or abandoned at a higher or lower stratigraphic horizon. It is far enough from the expected limits of the pool to make its outcome uncertain but it is not far enough to be designated as a wildcat. If it is successful in its original objective, it will add materially to the productive area of the pool. It is not the Board's normal practice to apply the outpost classification to a well located less than two drilling spacing units from the nearest well in the pool. Such a well is usually classified as a development well.

1.2 Development Category

The class of well licensed under this category is defined below. Such wells contain development metreage only. However, an exception may exist where a development well is re-entered and deepened. The Board will, upon the request of the licensee, determine which part, if any, of the deepened interval constitutes exploratory metreage.

A development well (DEV) is a well drilled with the objective of further exploiting the productive zone of a pool. Such a well may be inside the pool as already outlined by wells, or it may be a relatively short distance outside these limits.

On the basis of this definition, the Board normally assigns the development classification to an "edge well" located a relatively close distance (e.g. one or two drilling spacing units, depending on geological factors) beyond the nearest well in the pool. Furthermore, the development classification may be employed by the Board where the well is to be drilled slightly deeper than the target pool, especially where the strata to be penetrated have little or no hydrocarbon-bearing potential below, and in the vicinity of, the pool.

A sixth class of well, known as a "shallower pool test", is recognized as a part of the exploratory category under the Lahee well classification system. A shallower pool test is a well located within the known or expected limits of an established pool and drilled with the objective of exploiting a pool thought to exist above the established pool. Such a well, however, is normally classified by the Board as a development well because, before the well is spudded, the existence of the target pool has usually been suspected on the basis of data available from the up-hole portion of adjacent wells.

2 IMPLEMENTATION OF THE WELL CLASSIFICATION SYSTEM - POLICIES AND PROCEDURES

2.1 Technical Considerations

(a) When classifying a well, the Board takes into account such considerations as the geological objectives and projected total depth of the well, the geological conditions and known existence of hydrocarbons in the area in which the well is to be drilled, and, in its judgement, the general degree of the risk of failure involved.

(b) The oil- and gas-bearing portions of a pool consitute a single accumulation pursuant to both industry tradition and section 1(1)(q) of the Oil and Gas Conservation Act. Therefore, step out wells drilled to encounter the oil leg of a known gas pool are usually classified as development wells.

(c) Board-designated pool orders (G orders) have no bearing on the class of well, although they do affect the well's confidential status. Such orders are disregarded for well classification purposes because they may not have been issued for nearby pools, or because their boundaries have not been updated to reflect current knowledge regarding the areal extent and continuity of the pools.

(d) The outcome of a well, whether successful or unsuccessful in encountering oil or gas, has no bearing on the classification initially assigned to the well.

2.2 Administrative Considerations

(a) For practical reasons, the Board classifies a well when it is licensed. It recognizes, however, that according to established Lahee concepts, the classification of a well is intended to take into account the conditions that are known when the well is spudded.

(b) In view of (a), above, the Board may re-classify a well from the exploratory to development category if additional knowledge affecting the well's classification was gained before the well was spudded.

(c) The assigned well classification is recorded on both the issued well licence and the daily listing of well licences, and it is published and maintained on the records associated with the well.

(d) The Board, on its own initiative, may amend the classification of a well to accommodate an amendment to the well licence, to reflect failure to comply with the intentions recorded on the well licence application, or to provide for the correction of an obvious clerical error. For example, the classification may be amended if the well does not reach the projected total depth recorded on the well licence.

(e) The Board may classify the second and subsequent wells drilled after the discovery of new pool as development wells, if they meet the meaning of the definition.

(f) When it initially classifies a well, the Board does not take into account the impact of the classification on the Exploratory Drilling Assistance Program or any other regulatory consideration. Furthermore, to ensure consistency and impartiality, the Board does not, at this stage, entertain technical representations or opinions from the licensee concerning the classification of its well.

3 MISCELLANEOUS MATTERS

3.1 Prognostic Well Classifications

Before a potential well is licensed, an operator may enquire, in writing, as to the classification the Board would assign to the well if it were licensed at the time of the enquiry. The letter of enquiry shall state the location and intended total depth of the potential well, and the names of the anticipated productive and terminating formations. Supporting technical arguments or evidence respecting the requested service should not be included in the letter of enquiry because, as mentioned under section 2.2(f), such information is not considered by the Board when it classifies a well at the time of licensing.

The enquiry shall be accompanied by a cheque, payable to the Energy Resources Conservation Board, in the amount of $50 for each prognostic well classification requested.

The prognostic well classification determined by the Board will not necessarily coincide with the official classification assigned at the time of licensing, particularly where additional subsurface information becomes available between the enquiry and spudding dates.

3.2 Review of a Well Classification

An operator may, in writing and within 14 days following the spudding in of a well, request the Board to review any official or prognostic well classification determined for the well. The letter should indicate the change being requested and include any technical or other arguments or evidence to support the proposed change. For each such request received by the Board before 1 May 1986, the Board's current fee of $75 per review will apply. Thereafter, a fee of $100 per review will be charged. The fee is payable by cheque to the Energy Resources Conservation Board and is to accompany the request. The payment will be refunded where, in the opinion of the Board, a Board-committed clerical error has been the cause of the review being requested.

The review will be conducted by a senior member of the Board's staff, whose decision will be conveyed to the enquirer in writing.

Any questions regarding this letter may be directed to the Board's Geology Department at 297-8212 or 297-7515.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom
Board Member

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Energy Resources Conservation Board
640 Fifth Avenue SW
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Informational Letter IL 86-5

To: All Oil, Gas and Pipeline Operators May 20, 1986

THE PRORATION PLAN, SUPPLEMENTAL SALES AND SHUT-IN PRODUCTION

In recent weeks there has been references in the media to the proration plan, supplemental sales and shut-in production. About a week ago the Standing Senate Committee on Energy, Mines and Resources requested the ERCB to present information about these matters. On May 13, 1986 the Board filed the attached submission.

The submission shows that:

1. During January to May 1986, shut-in production averaged 109,000 barrels per day (17.3 x10^3m^3/d). The peak month was April with a shut-in of 164,000 barrels per day (26 x 10^3m^3/d) and May is expected to be 87,000 barrels per day (13.8 x 10^3m^3/d).

2. The cause of the shut-in is insufficient pipeline delivery capacity. Both the Interprovincial and TransMountain systems have been operating at full capacity since November, 1985. The Rangeland system has had some 12,000 to 15,000 barrels per day spare capacity in the December, 1985 to March, 1986 period but has been utilized to its capacity in the last two months.

3. The Supplementary Sales System became effective October 1, 1985. Supplementary sales during the last eight months have averaged 60,000 barrels per day (9.5 x 10^3m^3/d) or 5 per cent of the total demand for Alberta light oil. The peak month was March with sales of 114,000 b/d (18.1 x 10^3m^3/d) for 11 per cent of demand. The estimated sales for May are 26,000 barrels per day or 2 per cent of light oil demand.

A review of the evidence presented to the Senate Energy Committee, and accounts in the media, indicate that the foregoing facts, as well as other information about the proration plan and supplementary sales, are not well known and understood. To assist the industry in keeping up to date on these matters the Board has decided to issue a brief monthly report summarizing the basic facts.

The Board notes the recent criticisms of the proration plan with some concern. It has previously indicated to industry that changes to the plan can only be achieved through an application and public hearing unless there is a general concensus in industry. It recognizes that the plan elicits a wide spectrum of conflicting views in the industry and is attempting to assist in the resolution of those differences by the Industry/ERCB Proration Task Force which was established in April, 1985. However, the Board wishes to make it clear that if any party wishes the plan to be either modified or eliminated, an application should be filed with the Board and a hearing would then be convened.

As indicated in the attached report, the Board does not take a position respecting the proration plan - it neither supports it nor opposes it.

The current deficiency in pipeline capacity is a difficult problem but there may be ways to minimize it. The Board would welcome any suggestions.

Vern Millard
Chairman

Attachment

SUBMISSION BY THE

ENERGY RESOURCES CONSERVATION BOARD

CALGARY, ALBERTA

TO THE

STANDING SENATE COMMITTEE ON

ENERGY MINES AND RESOURCES

OTTAWA, ONTARIO

MAY, 1986

A REVIEW OF CURRENT ISSUES RELATING TO THE ALBERTA PRORATION PLAN

BACKGROUND

1. In 1950 industry requested the Alberta government to enact legislation that would permit the Petroleum and Natural Gas Conservation Board (now the Energy Resources Conservation Board - ERCB) to prorate production to market demand. The request was made because a series of major oil discoveries had resulted in productive capacity outstripping the capacity of the pipeline system. The new legislation permitted the Board to prorate, but specified that it must be done by determining the total market demand, allocating the demand to pools in a reasonable manner and distributing the pool allocation to the wells in a pool in an equitable manner. Following a public hearing the Board adopted a proration formula and issued the first Market Demand Order in December, 1950. The formula was changed significantly in 1964 following extensive public hearings. The plan was reviewed again in 1975 at a public hearing but the Board decided that changes were not required.

2. During most of the 1950's the growth in Alberta light oil* productive capacity continued to outpace the expansion in the pipeline delivery system even though the market area increased rapidly. In the 1960's import restrictions imposed by the United States severely limited the demand for Alberta oil.

* Light oil in this report means conventional light and medium gravity crude oil.

During the 1970's, restriction by the NEB on exports of oil from Canada had a similar effect. Those restrictions were lifted in 1983 and subsequently demand was reasonably in balance with productive capacity and the proration plan was essentially dormant. Beginning in 1985 the delivery capacity of the Interprovincial Pipe Line system became inadequate to transport all of the oil destined for eastern Canada and United States markets and the proration plan once again was called into service. Figure 1 provides a comparison of productive capacity and demand for Alberta light oil over the last 35 years.

3. Prorationing only applied to Alberta light oil. Heavy oil and pentanes plus were excluded in the initial plan because of their unique characteristics. Subsequently, and for similar reasons, synthetic crude oil from oil sands mining projects and bitumen from oil sands in situ operations were also excluded. Production from other provinces was also not subject to proration. Thus, the Alberta light oil pools became the "swing" supply source from western Canada. From time to time heavy oil has been subject to market problems and production has been restricted - usually a type of pipeline prorationing.

The relative importance of Alberta light oil has been declining as shown in Figure 2.

4. The proration plan involves the following procedures:

(a) purchasers file with the ERCB in mid-month their requirements (nominations) for Alberta oil for the following month,

(b) following a hearing to consider those requirements, the ERCB determines the total market demand and then subtracts the pentanes plus, synthetic oil, heavy oil and bitumen to determine the demand for light oil,

(c) the light oil demand is allocated to pools according to the proration formula adopted after public hearings which is based on reserves adjusted for production but provides for a minimum allowable for each producing well,

(d) the pool allocation is distributed to wells according to a prescribed formula designed to protect the equity of all producers in the pool,

(e) the ERCB issues an MD Order about the 25th of the month which specifies the production allowables for all wells and pools for the coming month,

(f) a production surveillance program with penalties for overproduction ensures that operators abide by the prescribed production allowables.

5. Because oil is a migratory resource and because recovery is frequently affected by withdrawal rates, there would need to be a "production control" system even if there was not a proration plan. However, many light pools (currently 675) have been placed on "good production practice" which means that they can produce at the discretion of the operator subject to certain basic requirements. The production from those pools is not affected by the proration plan.

RECENT EVENTS

1. In 1984 it became apparent that the delivery capacity of the Interprovincial Pipe Line system would not be adequate to deliver all the oil likely to be tendered to it, and plans were made to increase its capacity. Beginning in 1985 deficiencies began to occur from time to time and oil had to be shut in. In contrast, there was unused capacity on the TransMountain system because previous Canadian oil deliveries to the Puget Sound area of the United States had been displaced by oil supplied from Alaska. In order to minimize the shut-in of Alberta oil the

Federal government set the deemed value of exported oil at values to make it attractive in all export markets, and the capacity of TransMountain was more fully utilized.

2. On June 1, 1985, deregulation ended government involvement in price setting and the industry returned to a competitive pricing system with the major purchasers posting prices in the manner that prevailed prior to the imposition of price controls in 1973.

3. The initial price postings were apparently not attractive to refiners located on the periphery of the market area for Alberta oil and demand declined significantly in June and July. As prices were adjusted, demand generally recovered in some of the traditional export markets, as is indicated in Table 1. The demand for Alberta oil in the Puget Sound area did not return until after the supplementary sales program was introduced.

4. During the first few months of price deregulation substantial volumes of Alberta oil were shut-in because of the reduced demand. In August, Amoco Canada proposed a modification to the proration plan to permit the purchase of oil that had been shut-in by the MD Order because of insufficient demand. Amoco contended that producers might be prepared to sell all or a portion of their shut-in oil at a special price in order to

penetrate less attractive markets. The details of the plan were developed and discussed with the two industry associations (CPA and IPAC). Both indicated agreement and the ERCB implemented the Supplementary Sales plan on October 1, 1985. Further comments on the plan are provided in a subsequent section.

5. The problem of inadequate pipeline capacity increased dramatically in 1986. During most of 1985 the deficiencies were limited to the Interprovincial system but if allowance was made for the unused capacity of the TransMountain and Rangeland systems, then productive capacity was usually less than total delivery capacity. However, that comparison tends to mask the situation because the more accessable markets were served by the Interprovincial system and its shortfall in capacity could not be compensated by surplus capacity on the other systems. As Shown in Table 2, there is currently a substantial shortfall in total delivery capacity. In April and May the shortfall was 164,000 and 87,000 barrels per day respectively. Further details respecting delivery capacity are provided in a subsequent section.

6. The volume of shut-in oil is dependent on three main factors; productive capacity, demand (primary + supplemental), and delivery capacity. Unfortunately, each factor changes almost every month which leads to confusion. Table 2 compares

productive and delivery capacity; Table 3 summarizes the changes in demand; Table 4 relates delivery capacity to shut-in volumes and Table 5 relates all these factors to shut-in volumes. Clearly, deficient pipeline capacity has been increasing in importance. It has been the major cause of shut-in oil commencing in December 1985 and in April and May is the only cause.

7. Some have attributed the shut-in Alberta oil to the proration plan and the ERCB. The data do not support those allegations. Indeed, the data demonstrate that oil production would be shut-in even if Alberta had neither a proration plan nor an ERCB. However, the proration plan does provide a means of sharing the deficiency in delivery capacity.

8. Some members of industry contend that the ERCB should unilaterally eliminate the proration plan. The fairness provisions in the Energy Resources Conservation Act prevent the Board from adopting that approach. The proration plan was adopted following applications by industry which were considered at public hearings. Currently a substantial number of companies contend that the proration plan should be retained, while another group argues the converse. The ERCB takes no position respecting the plan - it neither supports it nor opposes it. But because of the fairness provisions, it must give all parties

an opportunity to question and comment on any proposed change (including elimination) unless there is a general consensus supporting the change. In other words, to cancel or amend the proration plan requires an application to the ERCB. To date the Board has not received an application even though it has advised operators of that requirement.

THE SUPPLEMENTARY SALES PLAN

1. The supplementary sales plan operates as follows:

   (a) The ERCB issues its MD Order a few days before the end of the preceding month and advises prospective supplementary purchasers and producers about shut-in oil and unused pipeline space on any of the pipeline systems.

   (b) If there is shut-in oil and available pipeline space, any supplementary purchaser can advertise that it is willing to purchase a specified volume of the shut-in oil. Subsequently it advises the ERCB of the volume tendered by producers and the pipeline system being used. The ERCB ensures that those deliveries are compatible with the unused pipeline capacities.

(c) After the month of production the producer advises the ERCB of the volume supplied by each well to the supplementary purchaser and the allowable for that well is increased to recognize the supplementary production.

(d) A well that has an overproduction balance at the beginning of the month is not eligible for supplementary sales.

(e) If a new requirement for primary oil occurs during the month, the Board issues a revised MD Order which might require the supplementary purchaser to cut back on his purchases.

2. The industry appears to be unaware of the magnitude of supplementary sales. Table 3 provides details for the period since its inception. The sales have averaged 60,000 barrels per day or about 5 per cent of the total demand. The peak month for supplementary sales was March 1986 with sales of 114,000 barrels per day for 11 per cent of the total demand. In contrast, supplementary sales in May were only 26,000 barrels per day for 2 per cent of the total demand.

3. There also appears to be misunderstanding respecting the final destination of the supplementary sales. Table 6 summarizes the deliveries by pipeline system.

4. The ERCB believes that the supplementary sales plan complements the proration plan because it provides flexibility and incentive to increase markets for Alberta oil. This has always been a major disadvantage of the proration system. The success of the new plan is seen in the utilization of pipeline capacity.

Interprovincial - 100% utilization - October to May

TransMountain - 100% utilization - December to May

Rangeland - 100% utilization - April and May.

5. Critics of the plan contend that supplementary sales exert a downward pressure on prices. The ERCB is not aware of any evidence that supports the contention but recognizes that it might be correct. As the Board sees it, there are two basic alternatives - through supplementary sales ensure that the pipelines are fully utilized with some risk that the price of all oil might be affected, or discontinue supplementary sales and lose the price flexibility required for peripheral markets and risk having additional oil shut in. If the latter alternative were adopted, the ERCB believes it would be almost certain that significant additional volumes would be shut in because of the current volatile marketing circumstances.

6. Critics also contend that the supplementary sales system is being abused and purchasers in the primary market are obtaining their supplies at lower prices through the supplementary system. The ERCB has obtained detailed sales information from each supplementary purchaser commencing in January 1986. The data indicates that in a few cases supplementary oil has been sold in the Canadian market but the sales have been infrequent, the total amount has been small and the ERCB does not expect further occurrences. It is more difficult to judge whether the supplementary sales in the export market are truly supplemental or merely a substitute for sales that would otherwise have been made. However, the Board believes that the vast majority of the supplemental sales in export markets are incremental.

7. A copy of the several ERCB releases respecting Supplementary Sales are attached.

PIPELINE DELIVERY CAPACITY AND SHUT-IN OIL

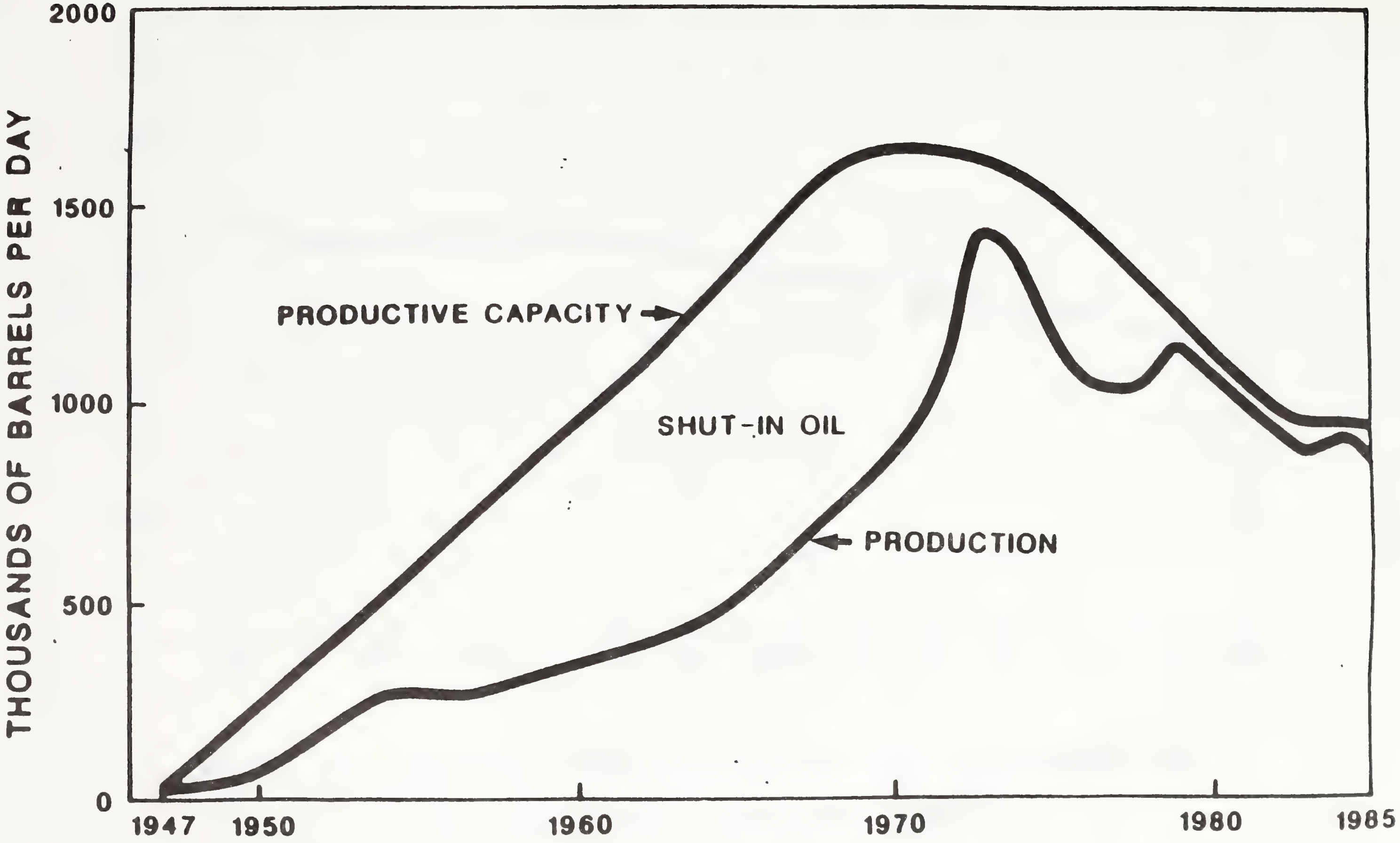
1. In order to analyze shut-in production, it is necessary to have regard for productive capacity, demand and delivery capacity. Under normal circumstances one would consider delivery capacity to relate to the pipeline systems transporting oil to markets outside the province. But allowance must also be made for oil delivered to Alberta refineries by the gathering system within

Alberta. Total delivery capacity as used in this report includes oil delivered to Alberta refineries (by within province pipelines) and the capacity of the ex-Alberta systems. That means that if Alberta refineries take less oil, the total system can absorb less oil and more oil is shut in if the delivery system is already operating at capacity. The impact of Alberta refinery requirements on total delivery capacity is shown in Table 7.

2. Because Alberta light oil is the "swing" supply source, the capacity of the Interprovincial system to deliver Alberta light oil is dependent upon production from other areas (Norman Wells, Saskatchewan), and production of other Alberta oils (pentanes plus, synthetic oil, conventional heavy oil and bitumen). The more oil that is produced from those other supply sources, the less space is available for Alberta oil. During the last two years there has been a dramatic increase in bitumen production from in-situ oil sands operations. That increase has had a much greater impact than just the increase in volumes because of its viscosity effects when injected into a line carrying light oil. The current configuration of the Interprovincial system results in each additional barrel of bitumen transported, displacing 2 to 3 barrels of Alberta light oil. Bitumen production in May 1984 was 22,000 barrels per day but one year later it was 46,000

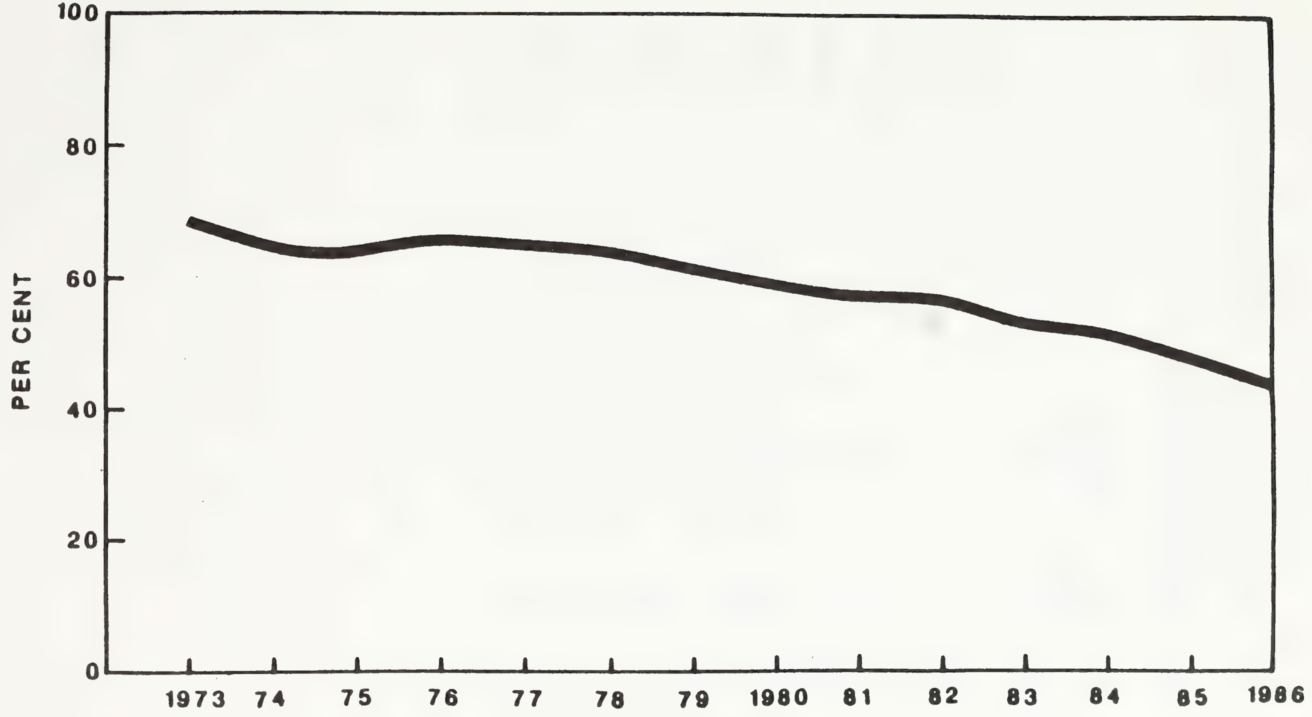
barrels per day and currently it is 87,000 barrels per day. This increase in bitumen production during the last two years has been the major cause of the reduction in ability to transport Alberta light oil.

3. Table 5 illustrates the linkage between productive capacity, demand and pipeline capacity with shut-in oil. Since March, 1986, the shut-in is entirely due to pipeline capacity, whereas in October and November it could be ascribed to demand related factors. However, that is really an over-simplification because the table shows the sum of the pipeline capacities and as previously indicated the TransMountain and Rangeland systems had spare capacity, whereas Interprovincial was fully utilized. It is likely that if the Interprovincial system had greater capacity in October and November, then the shut-in volumes would have been reduced or eliminated.



PRODUCTIVE CAPACITY AND PRODUCTION OF
LIGHT AND MEDIUM OIL IN ALBERTA

FIGURE 1



RATIO OF ALBERTA PRORATED LIGHT OIL COMPARED TO TOTAL WESTERN CANADIAN SUPPLY

FIGURE 2

TABLE 1

Purchasers Nominations
(Thousands Barrels per day)

	BC-Ontario	Quebec & Atlantic Prov.	Total Can.	Exports	Total
1985					
January	867	149	1016	147	1163
February	795	157	952	280	1232
March	824	166	990	285	1275
April	729	126	855	283	1138
May	822	90	912	286	1198
June	851	58	909	162	1071
July	835	83	918	153	1071
August	829	106	935	214	1149
September	781	83	864	225	1089

TABLE 2

COMPARISON OF ALBERTA LIGHT OIL AND EQUIVALENT PRODUCTION CAPACITY AND RELATED DELIVERY CAPACITY

(Thousand Barrels per day)

	Productive Capacity	Delivery* Capacity	Excess Delivery Capacity
1985			
October	1177	1217	40
November	1215	1260	45
December	1189	1170	(19)
1986			
January	1203	1180	(23)
February	1184	1077	(107)
March	1218	1094	(124)
April	1238	1074	(164)
May (Estimated)	1192	1105	(87)

* Including Alberta Refinery Requirements

TABLE 3

COMPARISON OF PRIMARY DEMAND AND SUPPLEMENTAL SALES FOR ALBERTA LIGHT OIL

(Thousand Barrels per day)

	Primary Demand	Supplemental	Total	Supplemental Sales %
1985				
October	1136	20	1156	1.7
November	1133	58	1191	4.9
December	1119	39	1158	3.4
1986				
January	1114	53	1167	4.5
February	1008	56	1064	5.3
March	965	114	1079	10.6
April	989	85	1074	7.9
May (estimated)	1079	26	1105	2.3

TABLE 4

COMPARISON OF EXCESS AND UNUSED DELIVERY CAPACITY AND SHUT-IN PRODUCTION

	Excess Delivery Capacity	Unutilized Pipeline Capacity			Shut-in
		IPL	TransMoun.	Rangeland	
1985					
October	40	-	43	18	21
November	45	-	50	19	24
December	(19)	-	-	12	31
1986					
January	(23)	-	-	13	36
February	(107)	-	-	13	120
March	(124)	-	-	15	139
April	(164)	-	-	-	164
May (Estimated)	(87)	-	-	-	87

TABLE 5

COMPARISON OF PRODUCTIVE CAPACITY, DEMAND AND DELIVERY CAPACITY

(Thousand Barrels per day)

	(1) Productive Capacity	(2) Primary Demand	(3) Excess Prod. Capacity (1 -2)	(4) Supplemental Sales	(5) Net Excess Capacity Shut-in (3 -4)	(6) Reasons for shut-in Demand Related*	Pipeline Capacity
1985							
October	1177	1136	41	20	21	21	
November	1215	1133	82	58	24	24	
December	1189	1119	70	39	31	12	19
1986							
January	1203	1114	89	53	36	13	23
February	1184	1008	176	56	120	13	107
March	1218	965	253	114	139	15	124
April	1238	989	249	85	164	-	164
May (Estimated)	1192	1079	113	26	87	-	87

* Assumes that all pipeline capacity is fully utilized.

TABLE 6

BREAKDOWN OF SUPPLEMENTARY SALES
(Thousand Barrels per day)

	Deliveries via IPL	Deliveries via TransMountain	Deliveries via Rangeland	Total
1985				
October	20	-	-	20
November	58	-	-	58
December	26	13	-	39
1986				
January	22	31	-	53
February	18	38	-	56
March	70	44	-	114
April	53	31	1	85
May (Estimated)	-	26	-	26

TABLE 7

BREAKDOWN OF DELIVERY CAPACITY FOR ALBERTA LIGHT OIL AND EQUIVALENT

(Thousands Barrels per day)

	Alberta Refineries	Ex Alberta Pipeline Capacity	Total
1985			
October	245	972	1217
November	268	992	1260
December	298	872	1170
1986			
January	323	857	1180
February	288	789	1077
March	288	806	1094
April	264	810	1074
May (Estimated)	272	833	1105

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MAY 26 1986

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Informational Letter

IL 86-6

TO: Crude Oil Producers and Purchasers 21 May 1986

MANAGEMENT OF SUPPLEMENTARY CRUDE OIL SALES

The supplementary crude oil program was introduced in October 1985, primarily to offer producers the opportunity to voluntarily sell some of their shut in oil to spot markets. As such, supplementary oil was not intended to undermine sales in the primary market or interfere with the disposition of oil produced for the primary market. Accordingly, the total volume of supplementary sales in any month was expected to be limited to the capacity of the extraprovincial pipelines to absorb and deliver that oil for spot sales.

Activity in the past few months suggests that the total volume of oil produced for supplementary sales has sometimes been excessive. The surplus production has created inventory control problems on the Interprovincial Pipeline System and hindered the disposition of oil produced to meet primary nominations. These developments are not compatible with the original intent of the program.

The Board believes that the problems are largely related to a lack of information to match supplementary production with surplus pipeline capacity. It expects that the problem can be resolved by compiling timely data on total oil movements and setting limits on supplementary sales by pipeline for each month. It proposes to implement the system outlined in Attachment 1 for gathering the necessary information effective 1 June 1986.

V. Millard
Chairman

Attachment 1 to IL 86-6

MANAGEMENT OF SUPPLEMENTARY CRUDE OIL SALES

The following system for limiting sales of supplementary crude oil in any month will take effect 1 June 1986.

- Extraprovincial pipelines (IPL, TMPL, and Rangeland) would be requested to advise the Board as to what incremental capacity exists to accommodate supplementary volumes without interfering with the movements of oil into the primary market. This would occur within a few days after the nomination hearing and would be updated periodically throughout the month of production.

- Given the incremental pipeline space available after full accommodation of primary oil on each extraprovincial line, the Board would limit the supplementary shippers to a level that would allow their purchases, plus the related royalty oil, to be accommodated in each line. After the proration hearing and throughout the month, the Board would monitor supplementary sales to all the shippers to ensure that pipeline space is not exceeded.

Details as to the workings of the proposed system are as follows:

1. The capacity available for supplementary oil would be determined by the Board on the basis of input from the pipelines and the nominations for oil in the primary market.

2. The Board would advise all supplementary shippers of the incremental pipeline space available on each system for such oil.

3. After the supplementary tendering process (advertising) the Board would request confirmation from all supplementary shippers as to

   - the pipeline space made available to each shipper for its supplementary sales (either direct shipment or by others), and

   - a nomination showing the disposition of the volumes the shippers will actually receive (net of royalty oil). This would be required in the first few days of each month or throughout the month as changes are made.

4. The Board would advise the APMC of the total volume of royalty oil tendered for supplementary sales and receive advice on the intended disposition from the Commission.

5. If the total tendered supplementary volumes (including royalty oil) exceed the incremental pipeline space, the Board will prorate the volumes to the level of the incremental capacity and notify the individual shippers of the reduced volumes that can be produced for the spot market in that month.

To permit the Board to monitor the above, we would request each shipper of supplementary oil to file nominations by the fifth business day of each month as identified in 3. With the assistance of the APMC (item 4), the Board should be able to inform supplementary shippers, by the 7th or 8th day of the month (as in item 5), as to whether their full supplementary volumes can be accommodated.

In the event that shippers or the APMC change their plans to purchase or dispose of supplementary oil throughout the month, or if additional space becomes available that would affect the marketing of supplementary oil, the Board must be notified immediately and permit an orderly change to the supplementary production.

For further information please contact the Economics Department at 297-3491.

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 86-7

4 July 1986

To: All Oil and Gas Operators

1986 WELL ADMINISTRATION FEE

The Board has established the 1986 Well Administration Fee at the rate specified in sections 16.070 and 16.080 of the Oil and Gas Conservation Regulations. In 1985 the fee was set at 90 per cent of the schedule and would have been set at 93 per cent for 1986 had it not been for the decision to construct a new industry blowout prevention training centre. Inclusion of funds for that centre has increased the 1986 fee to the level set out in the schedule.

It will be recalled that the Golden Spike Blowout Training Facility became inoperative during the summer of 1985. In January 1986 the Alberta Government and the industry agreed that there should be a new modern facility which would be jointly funded by government and industry. It was agreed that the facility should be owned by the ERCB and leased to the Petroleum Industry Training Service (PITS) to operate. The government provided its share of the funds in the Board's 1986/87 appropriation. The Board has decided to spread the industry share over the 1986 and 1987 Well Administration Fees.

Based on suggestions from industry, two minor changes have been introduced in the fee invoice format:

1. Property Codes. The Board has obtained industry property codes from Municipal Affairs and they will be included with the identification information for each well.

2. Sequence of Well Listing. The wells will be set out in unique well identification sequence rather than by battery.

In addition, where the operation of a well is undertaken by contract, the fee will be directed to the owner rather than the operator upon the written request of the owner. This request should include a complete description of the well, the name of the operator, it should be directed to the attention of Mr. D. Batten.

K. W. Fuller
Controller

ERCB

**Energy Resources
Conservation Board**

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

AUG 20 1986

Informational Letter

IL 86-8

TO: Coal Mining and Exploration Companies

17 August 1986

RELEASE OF RESULTS OF SPECIAL TESTS MADE ON COAL

As a responsibility under the Coal Conservation Act, the Board provides for the dissemination of information on the exploration, development, and utilization of coal.

In recent years, sufficient information resulting from special tests on coal has been compiled to warrant the release of such information. In general, the release of this information is considered to be in the public interest.

Special tests include tests for crushing, grinding, screening, washability, carbonization, and combustion.

The Board proposes to proceed with the release of the results of special tests in November 1986. In keeping with section 56 of the Coal Conservation Regulation, due notice will be given to each company prior to the release of information in the manner presently used for the release of drillhole logs and coal analyses.

N. A. Strom
Board Member

AL.1.151

CANADIANA
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JAN 12 1987

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 86-9

To: All Oil and Oil Sands Operators

14 November 1986

APPROVAL PROCEDURES FOR SINGLE WELL STEAM STIMULATION TESTS IN OIL SANDS AREAS

This letter supersedes Informational Letter IL 85-4 issued on 30 May 1985.

THIS LETTER OUTLINES a more rapid, less formal review system for approval of single well experimental oil sands tests that come under section 10 of the Oil Sands Conservation Act. The Energy Resources Conservation Board (ERCB) and Alberta Environment (AE) have agreed to revised procedures for the approval of single well (single and multiple cycle) steam stimulation tests that are aimed at preserving a high level of technical soundness and environmental safety, while providing operators with the flexibility to plan and carry out such tests with minimal regulatory review. Applications for such tests must meet the attached guidelines in order to receive rapid approval. The ERCB, on behalf of itself and AE, on a "one window" basis will issue a letter of approval confirming the undertakings included in the application. Since the guidelines establish the rules for the single well experiments, the ERCB would not anticipate a need to add any special conditions in its letter of approval.

For this purpose, a "single well" will be defined as not more than one test well per oil sands zone evaluation per quarter section.

The attached Application for a Single Well Steam Stimulation Test should be completed for each individual well, although more than one well may be covered by a letter of approval. The application form(s) should be attached to a covering letter which outlines the experimental objectives of the test(s) and any details or operations not adequately addressed or covered in the application form.

THIS SPECIAL ACCELERATED APPROVAL PROCEDURE WILL NOT APPLY for wells near populated areas or in sensitive environmental locations, where a more rigorous review would be needed. The accelerated approval also would not ordinarily include injection of other fluids such as carbon dioxide (CO_2), or which incorporate more complex production operations. Where operations involve interconnected injection facilities to several wells, permanent injection facilities, or operations judged to be for commercial (non-experimental) purposes, applications must adhere to the normal review, referral, and approval procedures.

ENERGY RESOURCES CONSERVATION BOARD

N. Strom

N. A. Strom
Board Member

ALBERTA ENVIRONMENT

C. L. Primus

C. Primus
Assistant Deputy Minister

ATTACHMENT TO IL 86-9

APPLICATION GUIDELINES

1. Applications shall be submitted to the Oil Sands Department of the ERCB. Several wells may be identified on the same application but each must be fully identified as to name, location, geological zone and depth, and well equipment.

2. Include only single wells which are to be steamed with a portable steam generator that does not exceed 14.6 megawatts (50 million Btu per hour) in capacity, burning sweet gas or other sweet, light hydrocarbon.

3. Identify size of steam slug in cubic metres (cold water equivalent) for each cycle and anticipated production (maximum rate and total for each cycle period).

4. Show that the appropriate mineral lease is held by the applicant.

5. Statement that the landowner and occupant plus any resident within 500 metres of the wellhead has been advised of the testing program.

6. Statement that the well cement, casing/tubing and completion is adequate for the test.

7. The proposed start and finish dates of the test(s).

8. Where there are residents in proximity to the well, there should be a fugitive emission detection and correction program to prevent nuisance odours. Outline the proposed program which should include the frequency of equipment inspection and the proposed monitoring instrument. Fugitive emissions of hydrogen sulphide must not result in the ambient concentration exceeding 0.01 parts per million on an hourly basis.

9. For single cycle tests the operator shall, within 60 days of completion of the test, submit to the ERCB a brief report summarizing the test and the air monitoring results. In the case of multiple cycle tests, the operator shall file annual progress reports with the ERCB commencing 1 year after the start-up of the test. The subject progress reports are due within 60 days of the expiration of each 12-month period.

Operating Guidelines

A. Injection Cycle

1. All filter and softener backwash fluids and boiler-blowdown and steam-venting fluids shall be piped directly to and contained in tankage until injected into an approved disposal well or disposed of in an environmentally safe manner satisfactory to the ERCB.

2. The equipment configuration on the test site shall be such that the steam generator is a minimum of 25 metres from the wellhead and the diked vent or blowdown tank is at least 25 metres from the wellhead.

3. Landowner approval shall be obtained before release of any water onto any land adjacent to the test site.

4. The local area office of the ERCB shall be informed of the proposed testing program and start-up dates prior to the commencement of any operation.

B. Production Cycles

1. All produced fluids shall be accurately measured and stored in diked tanks until sold or disposed of in a manner approved by the ERCB. Production reports should be identified as "Experimental".

2. The production cycle shall be monitored on a daily basis for the hydrogen sulphide content of both the gas produced via the casing and the gas coming out of solution from the produced fluids. A record of the monitoring results shall be kept by the operator at his field office or other place of business. A summary of the monitoring results shall be included in the progress report for the test(s).

3. Hydrogen sulphide shall not be emitted to the atmosphere.

4. When gases are to be flared, a 12-metre-high flare stack equipped with a suitable wind guard, continuously burning pilot, and ignition device shall be installed.

5. The operator shall dispose of produced sand in an environmentally safe manner satisfactory to the ERCB.

ERCB

Energy Resources
Conservation Board
640 Fifth Avenue SW
Calgary, Alta. T2P 3G4

APPLICATION FOR A SINGLE WELL STEAM STIMULATION TEST

1 PURPOSE

THIS APPLICATION FOR A SINGLE WELL TEST IS MADE UNDER SECTION 10 OF THE OIL SANDS CONSERVATION ACT.

THE PURPOSES OF THE PROPOSED TEST WILL BE TO ____________________

____

2 LOCATION AND DEPTH

SURFACE LOCATION OF THE WELL IS IN

LSD ____________ W ______ M

ACTUAL BOTTOM-HOLE LOCATION IS ☐ THE SAME AS THE SURFACE

OR ☐ IN LSD ____________ W ______ M

TEST INTERVAL (MEASURED-NOT TVD) ____________ m

GEOLOGIC ZONE ____________________

3 DESCRIPTION OF TEST

PROPOSED START AND FINISH DATES OF THE TEST ____________________

☐ THIS IS THE ONLY WELL COMPLETED IN GEOLOGIC ZONE IDENTIFIED ABOVE TO BE TESTED IN THIS QUARTER SECTION.

☐ A PORTABLE STEAM GENERATOR, NOT EXCEEDING 14.6 MW (50 M BTU/HR) IN CAPACITY WILL BE USED FOR THE TEST.

WATER-USE PERMIT ☐ YES ☐ NO

FUEL FOR STEAM GENERATOR ☐ SWEET GAS ☐ SWEET OIL ☐ PROPANE ☐ OTHER ____________

INFORMATION REQUIRED FOR EACH CYCLE:

STEAM SLUG SIZE ____________________

STEAM INJECTION PERIOD (DAYS) ____________________

MAXIMUM PRODUCTION RATE (m^3/D) ____________________

TOTAL PRODUCTION FOR EACH CYCLE PERIOD (m^3) ____________________

☐ ALL FILTER AND SOFTENER BACKWASH FLUIDS AND BOILER-BLOWDOWN AND STEAM-VENTING FLUIDS WILL BE CONTAINED AND DISPOSED OF IN ENVIRONMENTALLY SAFE MANNER SATISFACTORY TO THE ERCB.

☐ THE ENTIRE TEST SITE IS DIKED WHERE NECESSARY TO CONTAIN SURFACE RUNOFF FROM THE TEST SITE.

☐ LANDOWNER APPROVAL WILL BE OBTAINED BEFORE RELEASE OF ANY WATER ONTO ANY LAND ADJACENT TO THE TEST SITE.

☐ THE OPERATOR AGREES TO ACCURATELY MEASURE THE INJECTED AND PRODUCED VOLUMES AND TO REPORT THEM MONTHLY TO ERCB AND TO SUBMIT TO THE ERCB A PROGRESS REPORT SUMMARIZING THE RESULTS OF THE TEST.

☐ ALL PRODUCED FLUIDS WILL BE STORED IN DIKED TANKS.

☐ THE PRODUCTION CYCLE WILL BE MONITORED ON A DAILY BASIS FOR HYDROGEN SULPHIDE (H_2S) CONTENT OF BOTH THE GAS PRODUCED VIA THE CASING AND THE GAS COMING OUT OF SOLUTION FROM THE PRODUCED FLUIDS (GAS OFF STORAGE TANKS). THE MONITORING RESULTS WILL BE SUMMARIZED WITH THE TEST PROGRESS REPORT.

ANY H_2S PRODUCED WILL BE CONVERTED TO SULPHUR DIOXIDE (SO_2) BY COMBUSTION THROUGH

☐ 12 METRE FLARE STACK ☐ PORTABLE INCINERATOR ☐ OTHER (PROVIDE DETAILS)

☐ THE OPERATOR AGREES TO CARRY OUT THIS TEST IN A TECHNICALLY SOUND, ORDERLY, EFFICIENT AND ENVIRONMENTALLY SAFE MANNER, WITHIN THE CONTEXT OF THE GUIDELINES OUTLINED IN INFORMATIONAL LETTER IL86-9.

☐ THE LOCAL AREA OFFICE OF ERCB WILL BE INFORMED OF THE TEST AND START-UP DATES PRIOR TO COMMENCEMENT OF OPERATIONS.

PLOT PLAN-LOCATION OF AND SPACING BETWEEN EQUIPMENT

☐ PLOT PLAN ATTACHED

4 PRODUCTION CASING

CASING TYPE	INTERVAL DEPTH (m) BOTTOM JOINT TO TOP JOINT	SIZE (mm)	LINEAR DENSITY (kg/m)	GRADE	COLLAR TYPE	DETAILS OF CEMENT USED

OS 2(a)-86-11

5

SURFACE IMPACT

☐ THE PROPOSED SINGLE WELL TEST IS AT LEAST 1.5 km FROM THE CORPORATE LIMITS OF A CITY, TOWN OR VILLAGE.

IF NOT, DISTANCE TO CORPORATE LIMITS IS ____________ m

☐ THE PROPOSED SINGLE WELL TEST IS AT LEAST 100 m FROM THE NORMAL HIGH WATER MARK OF ANY SIGNIFICANT WATER BODIES.

IF NOT, DISTANCE TO NORMAL HIGH WATER MARK IS ____________ m

☐ THE PROPOSED SINGLE WELL TEST IS AT LEAST 100 m FROM ANY SURFACE IMPROVEMENTS .

IF NOT, LIST DISTANCE AND TYPE OF SURFACE IMPROVEMENT ____________

A BRIEF DESCRIPTION OF FUGITIVE EMISSION DETECTION PROGRAM PLANNED ____________

6

☐ THE APPLICANT HAS THE RIGHT TO PRODUCE CRUDE BITUMEN FROM THE ZONE OUTLINED IN THIS APPLICATION.

7

SURFACE RIGHTS

☐ THE SURFACE OWNER OF THE LAND USED BY THE APPLICANT HAS BEEN ADVISED OF THE DETAILS OF THE TEST, INCLUDING THE EQUIPMENT THAT WILL BE USED.

☐ THE SURFACE OCCUPANT OF THE LAND USED BY THE APPLICANT HAS BEEN ADVISED OF THE DETAILS OF THE TEST, INCLUDING THE EQUIPMENT THAT WILL BE USED.

☐ ALL RESIDENTS OF OCCUPIED DWELLINGS LOCATED WITHIN 500 m OF THE WELL HAVE BEEN ADVISED OF THE DETAILS OF THE TEST .

8

AUTHORITY

APPLICANT ____________	MAILING ADDRESS ____________	
CITY ____________	PROVINCE ____________	POSTAL CODE ____________
THIS APPLICATION DATED AT ____________	THIS ____________	DAY OF ____________
SIGNATURE ____________	TITLE ____________	TELEPHONE ____________
NAME (PRINT) ____________	COMPANY ____________	
FOR ADDITIONAL INFORMATION CONTACT ____________		TELEPHONE ____________

9

BOARD USE ONLY

DATE APPLICATION RECEIVED		AREA OFFICE
DESIGNATED OIL SANDS DEPOSIT	OIL SANDS SECTOR	DESIGNATED POOL OR ZONE

PRODUCTION CASING AND CEMENTING ADEQUATE ☐ YES ☐ NO

TEST EQUIPMENT AND CYCLE DETAILS IN ACCORDANCE WITH GUIDELINES IN IL86-9 ☐ YES ☐ NO

ONLY WELL IN QUARTER SECTION TO BE TESTED ☐ YES ☐ NO

SURFACE AND MINERAL RIGHTS SATISFACTORY ☐ YES ☐ NO

SPECIAL PROVISIONS OR REMARKS

EXPIRY DATE	APPROVAL LETTER SENT	ALBERTA ENVIRONMENT, ALBERTA ENERGY AND ALBERTA FORESTRY, LANDS AND WILDLIFE ADVISED ☐ YES ☐ NO	
PROCESSED BY	CHECKED BY	APPROVED BY	DATE

OS 2(b)-86-11

ADIANA
NOV 25 1986

ERCB

**Energy Resources
Conservation Board**

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 86-10

18 November 1986

TO: All Operators, Purchasers of Gas, Transmission Companies,
Utility Companies, Industrial Development Permit List,
Gas and Ethane Removal Permit List

UPDATE RESPECTING GAS REMOVAL MATTERS

This informational letter supplements Informational Letter IL 85-17 (Interim) which was issued on 4 December 1985.

Following the 31 October 1985 Intergovernmental Agreement on Natural Gas Pricing and Marketing, the Board issued Informational Letter IL 85-17 (Interim) outlining procedures for dealing with applications to remove not more than 3 billion cubic metres over periods of not more than 24 months, often referred to as small-volume/short-term gas removal applications. The letter indicated that the ERCB, at the request of the then Minister of Energy and Natural Resources, would review the formulae and procedures used in determining the volumes of gas surplus to Alberta's requirements. It also indicated that the procedures for small-volume/short-term permits would be used on an interim basis, until experience was gained.

This informational letter is to update all interested parties on matters related to those issues and is intended to supplement the procedures outlined in IL 85-17. It also deals with the manner of handling the "surplus situation" with respect to small-volume applications pending completion of the previously mentioned review.

Gas Surplus Review

In February 1986, the ERCB scheduled a hearing for 12 May 1986 to review its surplus formulae and procedures. It received requests from interested parties in industry to delay the hearing so that the results of the National Energy Board review of the same subject would be available. The ERCB agreed to delay the hearing for a few months. Subsequent requests by the industry have prompted further delays.

Review of Certain Gas Removal Permits

In January 1986, the government authorized seven large-volume permits which had been applied for and heard by the ERCB about 4 years earlier. Because of the passage of time and changes in the marketing situation for Alberta gas, the Minister asked the ERCB to review the permits to ensure the gas would likely be delivered to the markets identified in the original applications.

That review is now complete. On the basis of the data submitted by the permit holders, and recognizing the current uncertainties in the North American natural gas marketing scene, the ERCB has recommended that no changes be made to the permits at this time (ERCB Report 86-B). Rather, further regular reviews should be made in future when, hopefully, fewer uncertainties will exist.

One result of the conclusion not to reduce the volumes contained in these permits is that reserves must continue to be set aside for the full permit volumes in the ERCB's surplus determination.

Small-Volume/Short-Term Applications

Following the Agreement, the ERCB on an interim basis, streamlined the procedures for handling applications for small-volume/short-term permits. The requirements for supporting information and its review were significantly reduced. Also, because a letter from the Minister indicated the government's intent to eliminate the incrementality test, and because the volumes were small with short permit terms, the notice process to allow public input to the ERCB decision was greatly modified. In addition, because each permit would have a negligible impact on the provincial surplus situation, and the reviews of the surplus formulae and the seven large-volume permits were not complete, the ERCB decided not to apply a surplus test for each application. Rather, it would periodically review actual removals to satisfy itself respecting the impact on the surplus.

The revised approval system has now been in existence for nearly a year and although the surplus review hearing is intended, in part, to review "The treatment of short-term small-volume gas removal applications as set out in IL 85-17 (Interim)", it has not yet taken place. During this period a very large number of small-volume permits have been applied for, and many have been issued. Although each permit by itself has no significant impact on the provincial surplus, there have been about 120 applications which have either been approved or are awaiting Ministerial Approval or Order in Council, or are in earlier stages of processing by the ERCB. The total volume of gas involved is some 87×10^9 m^3 (3.1 Tcf), most of which is in permits already issued.

ERCB Views Respecting the Surplus Situation

The ERCB believes the following matters have a bearing on the surplus situation as it exists today.

- The review of the seven large permits is now complete with the recommendation that there be no change to permit terms and volumes.
- The hearing to review the surplus formulae has been delayed and as a result, the expedited process for handling small-volume applications, which was adopted on an interim basis, has been in effect longer than expected.
- The number of small-volume permits issued to date has been greater than expected. Although each permit is for a relatively small volume, the total volume approved under the expedited process is substantial.

Having these matters in mind, the ERCB is of the view that some action is necessary if it is to properly discharge its responsibilities under the legislation and in a manner consistent with the formulae it currently prescribes for surplus purposes. It believes an approach of using a detailed calculation for each small-volume application would be impractical. Rather than applying the test to each application, and recognizing the concern for the surplus situation, the ERCB has decided to adopt a limit of about 100 x 10^9 m^3 (3.5 Tcf) as the total volume it is prepared to approve for small-volume permits, until the surplus review is complete.

Such a limit would apply only to permit applications for small volumes which are being handled under the expedited processing system without a detailed review of surplus. It is not intended to prevent applications for small-volume removal permits that have supporting documentation showing that a surplus exists.

Recognizing that the limit on the total volume, as discussed above, may impact the approval of some applications in the future, the ERCB intends to increase its surveillance of existing permits. The ERCB will monitor all small-volume permits to determine which, if any, are not being used and may be rescinded. Such action would not be taken without consulting the permittee.

Due to the lengthy period since the initial notice of the hearing to review the surplus formulae and procedures, and given the concerns expressed earlier regarding the surplus and the resulting limitation on total removal volumes, and the government's 30 October 1986 policy statement respecting long-term protection for consumers of natural gas, the ERCB believes the surplus review hearing should take place in the near future and intends to schedule it for 13 January 1987.

Method of Processing and Required Information in Support of Removal Applications

The ERCB has reviewed the information requirements set out in IL 85-17 as well as the requirements for large volume applications. It has concluded that no major changes are necessary at this time.

However, considering the issues discussed in this IL and the recent changes to the legislation, the ERCB intends to increase its scrutiny of all applications for small-volume permits to satisfy itself that the pricing arrangements reflected in each application are in the Alberta public interest and that reasonably firm arrangements to market the gas are in place. This will involve the use of Method B as set out in IL 85-17 for processing all small-volume/short-term applications. A modification to Method B resulting from the recently revised legislation is that all applications for removal of volumes not more than 3 billion cubic metres over periods of not more than 24 months may be issued with the approval of the Minister of Energy. In addition, Method A, respecting the method of processing applications for removal of less than 1 billion cubic metres for terms not exceeding 24 months is deleted.

In addition to the above stated concerns, the ERCB needs to be assured that all applicants for removal permits either produce the gas to be removed or have made arrangements to acquire it, as is required under the legislation. Future applications should address this matter.

The increased scrutiny and revised procedure may result in lengthier processing times for applications.

An updated listing of requirements of applications for small-volume/short-term permits is attached.

This interim policy will be in effect until the completion of the surplus review. Questions or comments should be directed to the attention of Mr. Bill Schnitzler of the Gas Department at 297-7322 or Mr. Kevin Johnston of the Economics Department at 297-3233.

G J DeSorcy

G. J. DeSorcy
Vice Chairman